

EXHIBIT F



DEPARTMENT OF CONSERVATION

Managing California's Working Lands

Division of Oil, Gas, & Geothermal Resources

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TO: District Deputies
Underground Injection Control Staff

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SUBJECT: Underground Injection Control (UIC) Program Expectations

To better understand the roles and responsibilities of staff working in the UIC Program, the following standards (expectations) are provided to help ensure that UIC Program requirements are being applied in a manner consistent with the laws, regulations, primacy application, and agreements the Division is mandated to enforce.

Staff Expectations (Roles and Responsibilities)

1. All staff should adhere to and enforce all laws and regulations under the Division's authority. If the laws and/or regulations are unclear, it is each person's responsibility to ask for clarification.
2. All staff should adhere to and enforce the requirements of the Division's UIC Program with its mandated federal program requirements. If you do not understand UIC Program requirements, refer to the US EPA Primacy Application (AP) for clarification. If you still do not understand the program's requirements, contact the UIC Program Manager.
3. UIC Program staff should implement the major requirements of the UIC Program as outlined below in the Program Requirements and Conditions (please see below).
4. Some statutes or regulations allow for waivers or variances at the discretion of the District Deputy. Ultimately, the Supervisor of Oil and Gas is responsible for such an exercise of discretion and any decision to grant a waiver or variance must be vetted with the Supervisor or Chief Deputy.

5. The following requirements and conditions shall be implemented immediately.

UIC Program Requirements and Conditions

The following UIC Program requirements and conditions are provided to ensure that all staff are implementing the UIC Program as required by the laws, regulations, primacy application, and Division policy.

A. Existing Injection Projects

1. **Injection fluid must be confined to the permitted zone of injection.** This is required whether or not a USDW is present.

Confinement means:

- All wells (Primacy Agreement, p.2) within the "area affected by the (injection) project" (CCR §1724.7 (a) (4)) (Division's Area of Review - AOR) must have a minimum of 100 feet of cement in the annular space behind casing above the oil and gas zones and anomalous pressure intervals. A CBL or temperature survey (other methods may be used if approved by the State Oil and Gas Supervisor) should be used to evaluate and confirm top of cement in the annular space behind casing. If a CBL or temperature log is not available, the theoretical top of cement should be calculated. When calculating theoretical cement top, there must be enough cement to fill the annular space to at least 150 feet above the oil and gas zones or anomalous pressure interval. This 150' allows for a margin of safety when calculating theoretical top of cement. (The margin of safety allows for variations in hole size, cementing procedures, pre-flush conditions and displacement of fluids, and provides a conservative estimate of the top of cement.)

NOTE: Prior to 1978, Division regulations required 100 feet of cement in the annular space behind casing above oil and gas zones. Therefore, at a minimum, there should be at least 100 feet of cement in the annular space for all wells drilled before 1978 unless a variance is expressly provided by the Supervisor, based on known geologic conditions.

After 1978, regulation Section 1722.4 was amended to require 500 feet of cement in the annular space behind casing unless known geologic conditions supported adoption of a variance. Therefore, at a minimum, there should be at least 500 feet of cement in the annular space for all wells drilled after 1978 unless a variance has been expressly provided by the district deputy and the justification, as documented in the well file, is based on known geologic conditions. All variances, new or existing, to the cementing requirements described above must be cleared through the Chief Deputy State Oil and Gas Supervisor.

- All plugged and abandoned wells within the area affected by the project (AOR) must have cement across all perforations and shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shutoff holes, or the oil and gas zone, whichever is highest (CCR §1723.1). (Zonal Isolation is required by Section 3228 of the PRC.) In those rare cases where cement does not cover all perforations, for reasons such as the presence of junk in the hole, damaged casing, or that the well was drilled before clear standards were expressed in regulation, there must be, at a minimum, zonal isolation (PRC §3228). This means that the injection fluid must be confined to the approved zone and therefore should not be allowed to migrate up or down the wellbore into a non-approved zone.
- Injection fluid must not be allowed to migrate to a different zone through another well, geologic structure, faults, fractures, or fissures, or holes in casing. This includes prevention of injection fluid break through to the surface where the injection zone is exposed at the surface.
- Injection pressure must be maintained below fracture pressure, as determined by approved step-rate tests (CCR §1724.10(l)).
- All injection wells must have, in addition to cement above the oil and gas zones, cement across the base of freshwater interface (BFW) with at least 100 feet above the BFW interface.

Note: Historically, the Division has protected water quality of ~3,000 mg/l TDS or less. This is supported by both the State Water Resources Control Board Resolution No. 88-63 (included in the attached material) and the Federal aquifer exemption regulations (3,000 mg/l TDS or less is considered a major aquifer exemption). A minor aquifer exemption is required for water quality between 3,000 and 10,000 mg/l TDS. The Division's construction standards, consisting of the use of casing, mud, and cement, are adequate to prevent fluid migration and the comingling of lesser quality fluids. The hole and casing annulus space, between the top of the cement isolating the oil and gas zones and the base of the cement covering the BFW interface should have heavy mud to prevent the movement of fluids. Therefore, it is reasonable to conclude that the water quality of 10,000 mg/l TDS or less will be protected by the standards that are in place.

Failure to meet any one of these conditions without an appropriate variance indicates non-confinement, which is not allowed.

2. "Area affected by the project" (Division's AOR) will be determined using 1, 2 and 3 below:

- (1) One of the following methods:
 - a. Fixed radius (minimum $\frac{1}{4}$ mile) or
 - b. Calculated area,

and

- (2) Must include the distance in which the pressures in the injection zone may cause the migration of the injection and/or formation fluid outside of the proposed injection zone,

and,

- (3) The calculated injection time equal to the expected life of the injection project.

NOTE: The "area affected by the project," found in Division regulation Section 1724.7(a) (4), is comparable to the federal "Area of Review" with a few exceptions. The federal AOR definition is more detailed but not necessarily more encompassing. The Division's mandate is broader than the federal since it includes protection of all hydrocarbon resources and waters usable for irrigation and domestic purposes. The federal Safe Drinking Water Act protects public and domestic drinking water sources (USDWs). Since primacy, the Division's UIC Program encompasses protection of hydrocarbon resources, waters suitable for irrigation and domestic purposes, including USDWs.

The federal AOR (40 CFR §146.6) is determined using one of two methods: (a) the Zone of Endangering Influence; or (b) the Fixed Radius. The Zone of Endangering Influence is defined as "that area the radius of which is the lateral distance in which the pressures in the injection zone may cause the migration of the injection and/or formation fluid into an USDW and is calculated for an injection time period equal to the expected life of the injection well." The fixed radius method begins with a minimum $\frac{1}{4}$ mile radius and requires that other factors be considered when determining the AOR. These other factors include: the chemistry of the injected and formation fluids, hydrogeology, population and ground-water use and dependence, and historical practices in the area. Both these methods are instructive for Division staff to use when determining the area affected by the project, with the condition that fluid confinement to the permitted zone is mandatory.

3. All existing projects will have an annual project review. The purpose of the annual injection project review is to determine if the injection project still meets the permit conditions and is meeting its purpose; ensure that all required testing has been performed; determine if there have been any changes to the project, including if any wells have been drilled, reworked, or plugged and abandoned within the AOR and if the work was completed appropriately, to confirm that the injection fluid is

confined to the permitted zone of injection; and to confirm that no damage is occurring as a result of the injection project.

4. All required Mechanical Integrity Testing (MIT) must be performed within the timeframes established under §1724.10(j). The second part of the MIT must be performed within 3 months after injection begins. After that, testing must occur at the following frequencies:

- Water disposal: at least once per year
- Waterflood: at least once every two years
- Steamflood: at least once every five years

The deputy may grant a variance to this schedule for individual wells, but only for good cause if supported by documented evidence.

5. All Standard Annular Pressure Tests (SAPT) must be performed at least once every five years (CCR §§1724.10(f) and (j)(1)). For those situations where there is only a single string of casing across a USDW (10,000 mg/l TDS), the SAPT must be tested at the approved Maximum Allowable Surface Pressure (MASP) for the well. All tests must be evaluated to ensure casing integrity, i.e. that there are no leaks in the casing and that the fluid is confined to the permitted zone.
6. If the injection fluid is not confined to the intended zone or damage is known to be occurring, the operator must be ordered to cease injection. Operation of a project in a manner that is not consistent with applicable standards and permit conditions also may warrant such an order, depending on the nature of the noncompliance.
7. All injection wells must have a wellhead inspection at least once every two years and the injection pressure on the well tubing must be confirmed to be below the approved MASP. If the injection pressure is above the approved MASP, the operator must be contacted immediately and the operator must immediately reduce the injection pressure. There must be a database or records, listing the MASP for all injection wells, which is easily accessible to field personnel to verify that the MASP is not being exceeded.

B. New Injection Projects (Injection fluid must be confined to the proposed zone)

8. Injection fluid must be confined to the permitted zone of injection. This is required whether or not a USDW is present.
9. All required data (see checklist in Appendix A) must be submitted and evaluated to determine if there will be injection fluid confinement (CCR §1724.7).
 - a. Engineering study:

- I. Statement of the primary purpose of the project
 - II. Reservoir characteristics of each injection zone
 - III. Reservoir fluid data
 - IV. Casing diagrams - casing diagrams must be provided that include cement plugs, and actual or calculated cement fill behind casing, of all idle, plugged and abandoned, or deeper-zone producing wells within the area affected by the project, and evidence that plugged and abandoned wells in the area will not have an adverse effect on the project or cause damage to life, health, property, or natural resources (CCR §1724.7 (a) (4)). This includes casing diagrams of all sidetracked holes and redrills.
 - V. The planned well drilling and plugging and abandonment program to complete the project, including a flood-pattern map showing all injection, production, and plugged and abandoned wells, and unit boundaries.
- b. Geologic Study:
- I. Structural contour maps
 - II. Isopachous map
 - III. Geologic cross section through the injection well
 - IV. Representative electric log with notations of all formation tops, confining layers, geologic markers, depth of BFW interface, and any faults.
- c. Injection Plan:
- I. Map showing injection facilities
 - II. Anticipated MASP and pump rates by injection well
 - III. Monitoring system or method to be utilized to ensure that no damage is occurring and that the injection fluid is confined to the intended zone or zones of injection
 - IV. Method of injection
 - V. Cathodic protection
 - VI. Treatment of the injection fluid
 - VII. Source and analysis of injection fluid
 - VIII. Source well data
 - IX. Other data as required. (i.e. fluid compatibility study(s), etc.)

All data must be evaluated to determine if the injection fluid will be confined to the intended zone(s).

10. Step rate test(s) must be run to determine the fracture pressure of the injection zone(s) (CCR §1724.10(i)).

11. MITs must be performed on all injection wells (CCR §1724.10(j)). Prior to injection, each well must pass a pressure test of the casing-tubing annulus to determine the absence of leaks (CCR §1724.10(j) (1)). Within 3 months after injection has commenced a second MIT must be performed using an RA survey tool, and either a static temperature or spinner survey (CCR §1724.10(j) (3)). The District Deputy may

modify the schedule if supported by evidence, and as long as it does not exceed five years between MITs. (40 CFR §146.23)

12. If there is insufficient data to determine if the injection fluid is confined to the intended zone, additional information must be requested and used to confirm injection fluid confinement.
13. All cyclic steam and steam flood projects must meet the same data requirements as a waterflood project (CCR §1724.8) Steam flood projects have shown that the steam quality may no longer be fresh and therefore, pose a threat to freshwater.

C. Project Files and Well Records

14. A minimum of the last two injection MIT surveys must be maintained in the well file.
15. Step-rate test data must be maintained in both the injection project file and the well file of the well the test was performed.
16. Project files must be maintained up to date. This includes adding casing diagrams for any new wells drilled within the AOR, any step-rate tests conducted, annual project review documentation, project correspondence with the operator or other governmental organizations, and copies of any deficiencies, violations, civil penalties, or formal orders associated to the injection project. The project file must be maintained in a single location and clearly identified so that it can be easily pulled by district staff. The project file should also have documentation for all testing and survey scheduling, listing the last time the required testing/survey was completed.
17. Any well injecting into a non-hydrocarbon zone is defined as a water disposal well, even if there are zones with enhanced oil recovery. Therefore, a water disposal project application and approval is required.

D. Approval of an Injection Project Application

18. The project application approval checklist (Appendix A) must be completed that confirms that all required injection project data was received. All project data should be thoroughly evaluated and a written description with conclusions must be included in each section of the checklist.
19. The project application approval checklist must be forwarded to the UIC Program Manager, signed by both the reviewing engineer and the District Deputy, certifying that the injection project review process has been completed and the project meets program requirements. An electronic copy of the project application and draft project approval letter should be submitted with the project application approval.

checklist to the UIC Program Manager. The UIC Program Manager will review the application and draft approval letter for compliance with UIC program requirements (this is not necessarily a technical review). If necessary, modifications to the project will be specified prior to UIC Program Manager's signature. The UIC Program Manager will sign off on the project review and draft approval letter, if appropriate.